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GHGT-12

## Techno-Economic Study of Adsorption Processes for Pre-Combustion Carbon Capture at a Biomass CHP Plant

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### Abstract

An exemplary 10 MWth biomass CHP plant with a FICFB (Fast Internally Circulating Fluidised Bed) gasifier and Jenbacher type 6 gas engine was simulated to estimate the power and thermal outputs. The biomass-fuelled CHP plant was modified for carbon capture using either adsorption or amine process. It was found that a two-stage, two-bed PVSA (Pressure Vacuum Swing Adsorption) unit applied to syngas stream for pre-combustion capture spent less specific energy per captured CO<sub>2</sub> than a conventional amine process for post-combustion carbon capture. In particular, adsorptive carbon capture is very promising for this application since, in comparison to amine process, adsorption process is economical for small-to-medium scale gas separations, the capital cost is relatively low and it does not require the evaporating, corrosive amine solvents.

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**Keywords:** IGCC; Ultrapure hydrogen; Cogeneration; Pressure swing adsorption; Process simulation

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### 1. Introduction

Different technologies and processes are under consideration to reduce CO<sub>2</sub> emissions originating from combustion aiming to reverse the increase of the atmospheric CO<sub>2</sub> concentration that could lead to a harmful climate change [1]. The latest revisions of the IPCC report [2] highlighted application of carbon capture and storage to biomass-fuelled CHP plants for negative emission energy generation.

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Currently there are two commercial processes known to be most promising technologies for producing heat and power from biomass with sufficiently high efficiencies, such as 1) direct combustion of biomass combined with steam turbine and 2) biomass gasification for synthesis gas that fuels a gas engine for power generation. In particular the route by biomass gasification is preferred to direct combustion when higher power efficiency is targeted.

Biomass-fuelled CHP plants are naturally carbon-neutral so there is no additional CO<sub>2</sub> emitted to the atmosphere in running a biomass-fuelled CHP plants. If a carbon capture unit is integrated with the biomass-fuelled CHP plant, it is expected to achieve carbon-negative energy generation by consuming CO<sub>2</sub> in the air in the process of growing biomass through photosynthesis in overall.

When the CHP plant with biomass gasification is considered as a base case, it is conceivable to apply a carbon capture process to two different gas streams on the CHP plant. One is flue gases originating from both combustion reactor of gasification and gas engine and the other is a synthesis gas (syngas) stream generated by biomass gasification.

It is well known that the carbon capture from the flue gas can be performed effectively by amine processes. However as the syngas stream has a significantly lower flowrate and a higher CO<sub>2</sub> mole fraction (partial pressure) than the flue gas does, the optimal gas separation technology needs to be sought given the syngas condition. In case of 1 to 10 MW scale CHP plants, in particular, the syngas flowrate is so low that it can lie in the range of an adsorption process being considered as an alternative to conventional amine processes.

The adsorptive capture process applied to the syngas was designed to achieve over 95% CO<sub>2</sub> purity and 90% CO<sub>2</sub> recovery before fuel gas combustion in order to minimize the H<sub>2</sub> loss to CO<sub>2</sub> product. Since the feed gas pressure is close to atmospheric pressure, the adsorptive carbon capture design must be similar to a Pressure Vacuum Swing Adsorption (PVSA) system that has been developed for a post-combustion capture process [3 – 6]. They have reported the energy consumption of around 70 – 80 kJ<sub>th</sub>/mol CO<sub>2</sub> with well-designed adsorption processes, such as one-stage multiple-column system or two-stage, two-column system, that is almost half of 154 kJ<sub>th</sub>/mol CO<sub>2</sub> of MEA process [7]. However it should be noted that the figures do not include energy consumption for CO<sub>2</sub> compression and power loss caused by shift reaction and more importantly the specific energy consumptions per captured CO<sub>2</sub> should be compared in terms of power instead of heat reflecting the features of biomass CHP plant since heat-to-power conversion factor must be different over power plants.

In this study, it was aimed to construct a detailed process flowsheet for a biomass-fuelled CHP plant as a base case in the first place. Then the base case plant was integrated with two different carbon capture processes: a two-stage, two-column PVSA system and a MEA carbon capture process for comparing the energy penalties involved in the two carbon capture processes.

## 2. Base case: Biomass-fuelled CHP plant (FICFB gasifier + gas engine)

The biomass-fuelled CHP plant selected as a base case was simulated in reference to the existing plant [8]. In the process, the biomass feed is converted into a syngas at Fast Internally Circulating Fluidized Bed (FICFB) process and then the syngas is fed to a gas engine (GE Jenbacher Type 6). The process was designed on a basis of around 10 MW<sub>th</sub> thermal input of biomass feed. The process flowsheet is presented in Figure 1.

### 2.1. FICFB gasifier

The FICFB gasification process is composed of two reaction zones: gasification and combustion zones [9]. The biomass feed of which the properties are reported in [10] is gasified by in-situ generated steam (oxidant) and the heat carried by inert material coming from combustion zone. Approximate 15% out of total carbon contained in the biomass is not gasified but deposited on the circulating inert material. Also part of syngas is sent to the combustion zone. The remaining carbon on the inert material and the part of syngas are both burnt in the combustion zone to heat up the inert material to an extent that they can provide the sufficient heat for gasifying the biomass feed at the gasification zone. The thermal energy of two hot streams leaving the gasification and combustion zones are recovered by generating steam for gasifier, preheating air and syngas, and producing hot water. Gas engine

The Jenbacher Type 6 gas engine, currently one of the most advanced gas engines, was chosen for generating power since it serves the 1.5 to 4.4 MW power range with very high electrical efficiency ranging from 41% to 44%.

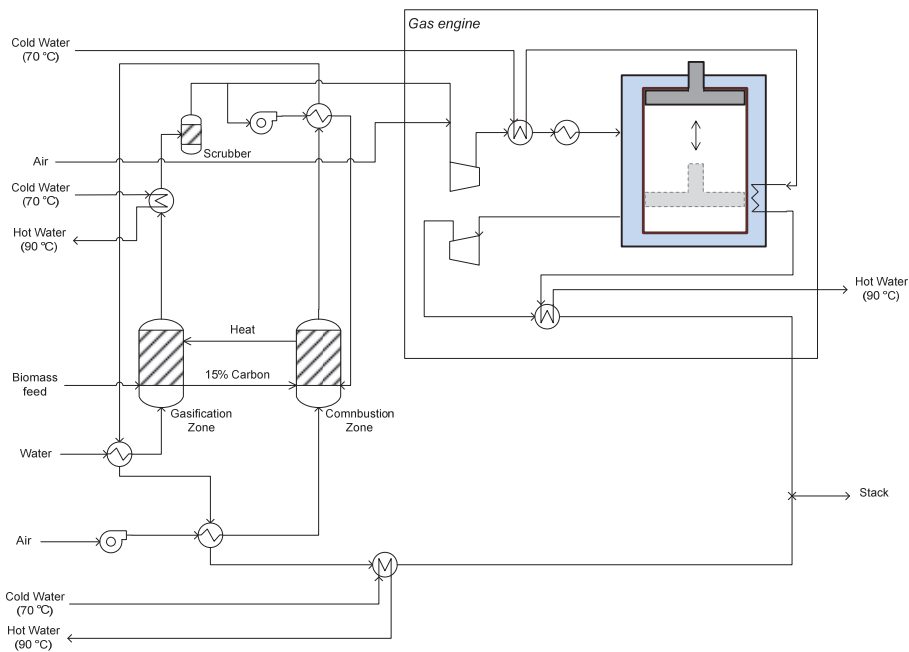


Fig. 1. Schematic diagram of a biomass-fuelled CHP plant containing a FICFB gasifier and a gas engine (Base case).

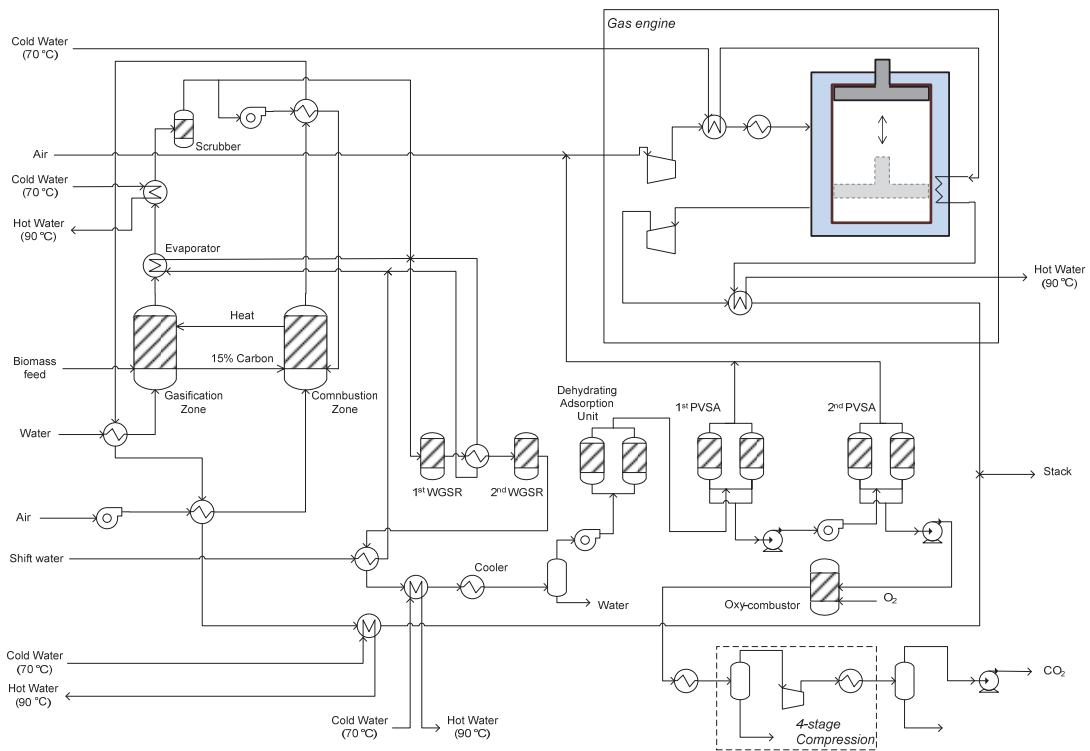


Fig. 2. Schematic diagram of a biomass-fuelled CHP plant integrated with a PVSA CO<sub>2</sub> capture unit (Case 1).

Among several Jenbacher Type 6 models J620 was chosen for this study since the electricity capacity (3.1 MW<sub>e</sub>) is close to those designed in this study. The gas engine was simulated using UniSim to find out the operating conditions. Constructing a reliable simulator for this gas engine is essential for estimating the power and thermal outputs of the gas engine running with a different feed gas. In case of a CHP plant being integrated with an adsorptive capture process, the gas engine runs with a syngas stream of which the composition is different from that in the base case since the syngas is treated by shift reactors and then decarbonised by adsorptive CO<sub>2</sub> capture unit. The turbocharging Otto cycle is configured as shown in Figure 1. The operating pressures and temperatures of compressor, turbine and various steps of Otto cycle can be found in comparison to the electrical and thermal performance data obtained with a natural gas having methane number = 70 under the conditions of meeting the following design factors [11]

- Mean efficiency pressure = 20 bar
- Compression ratio = 11
- The exhaust gas outlet temperature = 120 °C for natural gas, 180 °C for biogas
- Hot water temperature at inlet and outlet = 70 / 90 °C

The estimated electrical and thermal outputs of 45.35% and 43.49% are close to those reported [11]. It is well known that a gas engine would operate with less electrical and thermal efficiencies if it is fed by a fuel gas of which the heating value is lower. As the syngas stream in this study has a lower heating value of 199.1 kJ/mol that is lower than 634.5 kJ/mol of the natural gas, as expected the estimated electrical and thermal efficiencies were lowered up to 43.16% and 43.06%, respectively.

### 3. Case 1: Adsorption process for carbon capture

As mentioned earlier, an adsorption process would be advantageous over wet absorption processes for recovering CO<sub>2</sub> from a gas mixture having higher CO<sub>2</sub> concentration at small-to-medium scale industrial processes. Therefore, it is appropriate to choose adsorption process for capturing CO<sub>2</sub> from the syngas. As most of CO<sub>2</sub>-selective adsorbents exhibit very low CO adsorption amount, it is essential to convert most of CO to CO<sub>2</sub> by Water Gas Shift Reaction (WGSR) for achieving high carbon capture rate. Two-stage shift reactors composed of high-temperature shift reactor followed by low-temperature shift reactor was chosen to achieve 93.2% of overall CO conversion. The molar ratio of steam to CO in the feed to the 1<sup>st</sup> shift reactor is set as 2.0. Potentially the CO conversion could be increased by increasing the steam-to-CO ratio over 2.0 for achieving higher CO<sub>2</sub> capture rate at subsequent adsorption process. However the increase of steam-to-CO ratio requires greater consumption of thermal energy for producing more steam (decreasing the thermal output) and the resulting greater extent of exothermic CO conversion reduces the total heat input to gas engine by shifted syngas leading to decreasing the power and thermal outputs at the gas engine.

A two-stage, two-bed PVSA unit was configured for pre-combustion CO<sub>2</sub> capture as shown in Figure 2. The 1<sup>st</sup> stage PVSA is considered as a CO<sub>2</sub> enriching stage where the CO<sub>2</sub> mole fraction is increased up to around 75% with the CO<sub>2</sub> recovery maintained closely to 98%. The 2<sup>nd</sup> stage PVSA is regarded as a CO<sub>2</sub> purification step for increasing the CO<sub>2</sub> mole fraction from 75% to over 95% minimising the CO<sub>2</sub> loss for maintaining CO<sub>2</sub> recovery over 90%. Zeolite 13X was used as an adsorbent in this work. The gas composition of the shifted syngas after dehydration is 65.5% H<sub>2</sub>, 31.9% CO<sub>2</sub>, 1.7% CO, 0.8% N<sub>2</sub>, and 0.1% CH<sub>4</sub>. It is assumed that the feed gas is compressed up to 1.5 bar for the two PVSA units. It was aimed to design the PVSA unit for recovering around 90% CO<sub>2</sub> (approximately 86% carbon) from the feed gas.

Feed gas temperature is one of the key parameters in optimising PVSA units since the CO<sub>2</sub> working capacity estimated at the two CO<sub>2</sub> pressures of 0.48 bar (adsorption) and 0.095 bar (desorption) reaches its maximum at 60°C in the range of 0 to 90°C. Therefore the feed gas temperatures for the two PVSA units were controlled to 60°C before the feed gas enters the adsorption column.

The adsorption columns were sized to have the length of 3 meter for both units and the radius of 1.2 meter for the 1<sup>st</sup> PVSA and 1.0 meter for the 2<sup>nd</sup> PVSA. The performances of two PVSA units were simulated by an in-house adsorption process simulator [12, 13]. There are many parameters and operating conditions to be determined in

designing a PVSA system, such as step configuration, step times, adsorption and purge pressures and so on. It was found that there would be various sets of parameters and operating conditions, i.e. many alternate PVSA designs, to achieve the same performance of CO<sub>2</sub> purity and recovery. However the overall power consumptions for various two-stage PVSA configurations being devised to achieve the same CO<sub>2</sub> purity and recovery are close to each other. In this study the purge pressures for the 1<sup>st</sup> and 2<sup>nd</sup> PVSA units were set as 0.2 bar and 0.4 bar, respectively.

A small H<sub>2</sub> and trace amounts of CO and CH<sub>4</sub> slip into the CO<sub>2</sub> product cannot be avoided. The hydrogen contained in the CO<sub>2</sub> product should be removed before the CO<sub>2</sub> product is sent to the CO<sub>2</sub> compression unit. It is assumed that the 4.7% H<sub>2</sub> in the CO<sub>2</sub> product are simply burnt with pure oxygen. The resulting CO<sub>2</sub> purity can be increased up to over 99% after separating out condensed water between compression stages.

The WGSR decreases the LHV of the fuel gas due to its exothermic reaction. However the CO<sub>2</sub> is removed out of the shifted gas by the PVSA units, which increases the LHV of the fuel gas. As a result the LHV of the fuel gas was increased slightly up to 230.3 kJ/mol from 199.1 kJ/mol of the original syngas. The electrical and thermal efficiencies of gas engine was slightly increased by 0.4% due to the increase of the LHV (see Table 1).

Once the CO<sub>2</sub> is captured by a PVSA system, it is compressed by a CO<sub>2</sub> compression system up to 150 bar. The CO<sub>2</sub> compression system is made up of four-stage compression with intercooling and subsequent CO<sub>2</sub> pump.

#### 4. Case 2: Amine process for carbon capture

A conventional amine capture process using 30wt% aqueous MEA was attached to the flue gas stream for capturing CO<sub>2</sub> up to 90% as shown in Figure 3. The configuration and operating conditions of conventional amine process were detailed in earlier work [7]. It is well known that the required heat duty at the stripper reboiler can be minimised to around 3.5 MJ/kg CO<sub>2</sub> when the stripper operates at around 1.9 bar on the top. Since the pressure (1.9 bar) of CO<sub>2</sub> product being obtained at the steam stripper is higher than 1.1 bar at PVSA unit, the specific power consumption for CO<sub>2</sub> compression can be reduced. In addition to the use of LP steam, there is power consumption for a flue gas blower and several pumps but the total power consumption is small as shown in Table 1. A CO<sub>2</sub>-laden solvent is regenerated at a steam stripper being driven by in-situ generated LP steam. The required amount of LP steam is so huge that the heat recovery from two hot streams originating from the gasification and combustion zones is not sufficient. Therefore it is necessary to modify the thermal recovery system at the gas engine as well for producing LP steam as well as hot water at the gas engine.

#### 5. Economic analysis

The performances of three cases are summarised in Table 1. As expected, the adsorption capture unit (case 1) spent less energy for capturing unit amount of CO<sub>2</sub> than the MEA capture unit (case 2) by around 50%. However, the specific energy consumption per CO<sub>2</sub> captured does not include the energy consumption for steam generation required for shift reactions. To evaluate the energy penalty involved in shift steam, a hypothetical power loss was introduced assuming that the shift steam is sent to a virtual steam turbine. The shift steam at case 1 cannot be regarded as an IP steam due to its low pressure while the temperature (322 °C) is sufficiently high for IP steam. Therefore the steam pressure was assumed 12 bar only for evaluating the hypothetical power loss.

Since the amine process spent huge thermal energy for the stripper reboiler but relatively small power, the thermal output was greatly damaged from 5.03 MW<sub>th</sub> to 1.69 MW<sub>th</sub>. If the thermal output of the CHP plant with amine capture plant need to be kept the same as that of the base case, the biomass feed rate must be increased by 5.03/1.69, i.e. around 3 times. In other words, the ratio of power to thermal outputs at the CHP plant with amine capture unit would be very different from that at the base case. On the contrary adsorption processes spend both power (PVSA units) and thermal energy (shift steam) evenly so the ratio does not change much with carbon capture.

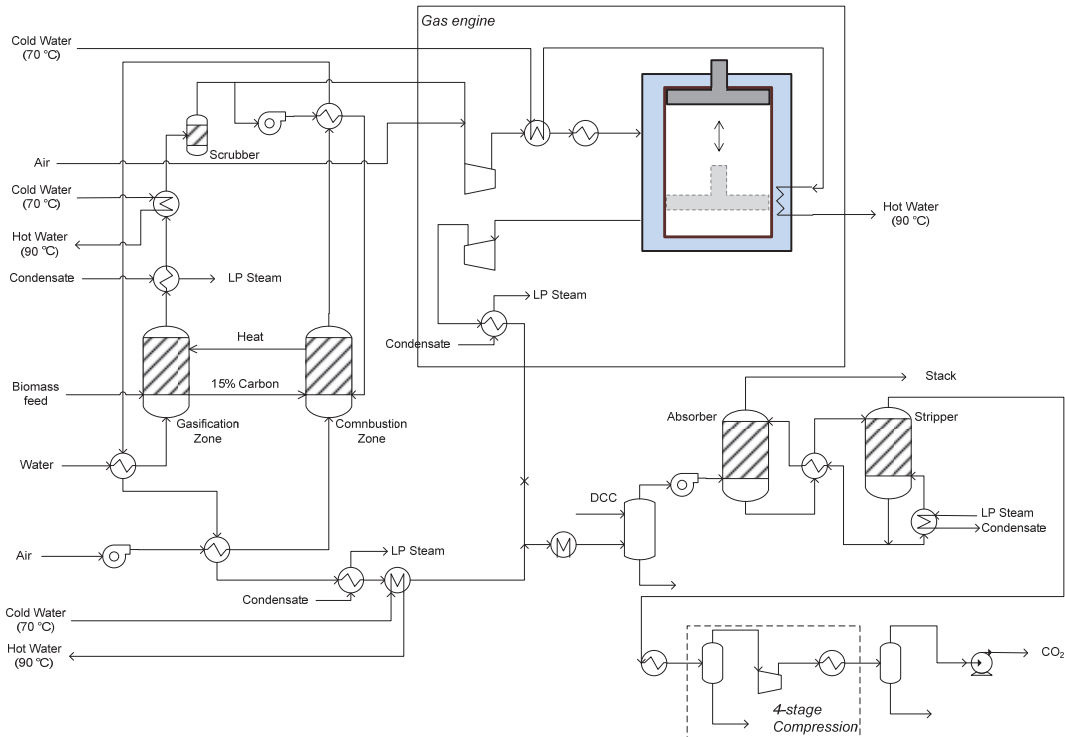


Fig. 3. Schematic diagram of a biomass-fuelled CHP plant integrated with a MEA capture unit (Case 2).

Table 1. Summary of electrical and thermal performances of the biomass-fuelled CHP plant.

	Base case	Case 1: PVSA	Case 2: MEA
Biomass heat input, LHV [MW <sub>th</sub> ]	10.07	10.07	10.07
Syngas LHV [kJ/mol]	199.1	230.3	199.1
Syngas heat flow, LHV [MW <sub>th</sub> ]	6.91	6.40	6.91
Gas engine performance			
Electricity production [MW <sub>e</sub> ]	2.98	2.80	2.98
Power efficiency on the basis of biomass/syngas	0.296 / 0.432	0.278 / 0.436	0.296 / 0.432
Hot water production [MW <sub>th</sub> ]	2.98	2.76	1.47
Thermal efficiency on the basis of biomass/syngas	0.295 / 0.431	0.275 / 0.430	0.146 / 0.213
LP generation for amine process [MW <sub>th</sub> ]	–	–	1.50 (0.149)
Heat generation at gasification (+ shift) section [MW <sub>th</sub> ]	2.06	1.79	0.211
LP steam generation at gasification section [MW <sub>th</sub> ] (efficiency)	–	0.634 (0.063) for shift reaction	1.85 (0.184) for amine process
Total hot water generation [MW <sub>th</sub> ] (efficiency)	5.03 (0.500)	4.54 (0.451)	1.69 (0.167)
Sum of electricity and heat efficiencies	0.796	0.729	0.463
Carbon capture unit			
Carbon capture rate on biomass basis [%]	–	47.0 (85.7 % on the syngas basis)	90.0%
Power consumption, capture unit [MW <sub>e</sub> ]	–	0.212	0.052
Heat consumption, capture unit [MW <sub>th</sub> ]	–	–	3.35
Power consumption, CO <sub>2</sub> compression [MW <sub>e</sub> ]	–	0.164	0.261
Overall net power production [MW <sub>e</sub> ] (efficiency)	2.98 (0.296)	2.43 (0.241)	2.82 (0.280)



Overall net hot water production [MW <sub>m</sub> ] (efficiency)	5.03 (0.500)	4.54 (0.451)	1.69 (0.168)
Specific energy consumption per CO <sub>2</sub> captured [MJ <sub>e</sub> /kg CO <sub>2</sub> ] (including CO <sub>2</sub> compression)	–	0.743 (1.15, including shift reaction)	1.38

## 6. Conclusions

Adsorption processes are one of the most promising technologies for capturing CO<sub>2</sub> from shifted syngas at small-to-medium size CHP plants as an alternative to post-combustion amine process. It was found that the specific energy consumption at adsorptive capture process would be as low as half of those at amine processes even though the energy saving effect is compromised to some extent by the energy penalty involved in shift steam generation. There is a restriction on the maximum carbon capture rate achievable with pre-combustion adsorptive carbon capture.

Nevertheless it is worth developing adsorptive capture processes further since 1) it requires relatively low capital investment cost in comparison to expensive amine processes and 2) carbon capture rate at the biomass-fuelled CHP plant does not have to reach 90+ % since biomass feed is carbon neutral.

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